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OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design

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Application No. 06-03-005

OPENING COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON DYNAMIC PRICING ISSUES RAISED IN ASSIGNED COMMISSIONER'S RULING OF AUGUST 22, 2007

William H. Booth
Law Offices of William H. Booth
1500 Newell Ave., 5th Floor
Walnut Creek, CA 94596
wbooth@booth-law.com
(925) 296-2460
925) 296-2464 facsimile
Counsel for the California Large Energy Consumers Association

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COMMENTS OF THE
CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION
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Dynamic pricing and time-differentiated rates are aspects of rate design, and one should begin with the question "what is the objective of electric rate making and rate design". Professor Bonbright offers several objectives or goals, including assurance of utility cost recovery, fairness in the recovery of utility costs as between customer classes, signaling to customers the actual costs of their consumption decisions and stability and predictability of rates. Regulators' ability to fulfill all of these objectives has been limited, to some degree, by the absence of meters that could record consumption by time period in sufficient granularity to allow proper and accurate price signals to be sent to customers. With respect to others, such as utility cost recovery, the Commission has adopted several measures (a wide variety of balancing accounts, decoupling of revenues from sales, attrition, etc.) that largely, if not entirely, remove any element of risk of cost recovery for the utilities.[1]

With regard to other aspects, technological limitations have held back progress. It is, for example, very hard to signal a residential customer who is served with a simple recording kWh meter that his air conditioning use during hot summer afternoons places enormous stress on the utility system and is quite costly. With the spread of time of use demand meters to more and more electric customers, indeed with the advances in metering and information technology that the Commission appears to support, new possibilities arise for rate design. It is thus timely for the Commission to consider once again dynamic pricing and time differentiated rates because it has new tools to permit implementation that previously were not available. CLECA is pleased to have this opportunity to comment on the many questions raised in Commissioner Chong's Ruling

[1] While it is a very good time to be a California utility shareholder, the removal of virtually all utility cost recovery risk creates a number of unintended consequences that are not beneficial for ratepayers, that tend to increase the overall level of rates, and that might lead to the adoption of rate designs which favor particular policy initiatives by masking and/or shifting costs.

and it pledges to work with the Commission as it grapples with these important ratemaking issues.

I. Objectives of dynamic pricing and time-differentiated rates

1. *What are the objectives of dynamic pricing and time-differentiated rates? How should the various objectives be prioritized?*

First and foremost, California electric rates should be designed to send price signals to customers of the cost of serving their loads to the greatest extent possible. Those signals need to be as accurate as is possible given the technology available, and they need to be as free from compromise and distortion as is politically possible. The single biggest enemy of efficient electric ratemaking in California is the fact that the existing rates are riddled with subsidies and compromise, subsidies between customer classes, between large and small customers within a class, between urban and rural customers, and between high load factor and low load factor customers. Rates must signal the cost of serving the incremental usage of a customer as well as the ongoing cost of the customer's connection to the grid. It is not sufficient to signal the customer through time of use rates that usage during hot summer afternoons strains the capacity of the generation and transmission systems, if rates concurrently ignore or mask the costs of the customer's connection to the grid, or are artificially capped, and thus subsidize his overall cost of electricity.

One of the most important objectives should be to design rates that reflect the type of cost to be recovered. Generation-related costs should be reflected in rates that let the customer know that the costs of serving the customer vary by time of day and season and that there are times when the incremental cost of serving the customer is very high because the supply-demand relationship is very tight.

Transmission and distribution-related costs should be recovered in rates designed to reflect the fixed cost of providing the customer with a connection to the grid. They may distinguish between costs that vary with demand and those that do not. The latter are considered customer-related distribution costs. Analysis must be performed to determine whether distribution-related capacity costs vary with time of day. If they do, it may be appropriate to establish time-varying distribution demand charges for the portion of distribution-related capacity costs that so varies. Unless there is solid analysis showing that distribution costs or customer costs vary with kWh consumption, these costs should not be recovered on a volumetric basis. Doing so would simply shift cost recovery to higher load factor customers.

Dynamic pricing and time-differentiated rates should send signals to customers to shift consumption to lower cost periods only to the extent that the costs are actually lower and only to the extent that the rate differentials reflect the cost differences. Rates should not be designed to induce behavior that is not justified by a difference in costs.

2. *How should dynamic pricing policy be coordinated with other policies and rate design considerations such as energy efficiency, greenhouse gas emission reduction, rate stability, rate simplicity, cost causation, and utility cost recovery?*

The most important underlying factor in rate design is to reflect cost causation and to signal the impact of a customer's consumption of utility costs. Dynamic pricing should focus on sending price signals that indicate that the cost of serving incremental customer load at some times is very high and at other times is much lower. This is much more important for demand response that it is for energy efficiency. Energy efficiency reduces peak loads if the kWh savings are permanent and occur during all hours or at least the peak hours. Savings kWh through energy efficiency measures also saves fuel and operating costs. So, dynamic pricing should focus on shaving peak period demands and thereby reducing the need for marginal generation capacity and improving the overall system load factors of the utilities. Dynamic pricing can lead to much more efficient use of embedded generation and transmission assets with lower overall costs to customers.

Customers value rate stability, especially in terms of rate design. Rate design should not change dramatically or frequently, and, when it does, it should be explained to customers and they should be provided with information to help them to respond to the changes. Rate simplicity is desirable, but what is more important is rate comprehension. Again, providing customers with assistance in understanding new rates and how they can respond to these rates is the key. Simple rates that do not reflect costs (such as the current non-time-differentiated residential rates) send the wrong price signals, encouraging customers to make consumption decisions at times of high cost that are not captured in the prices the customer sees. This is counter-productive.

Utility cost recovery is important, but the Commission has already provided the utilities with mechanisms to assure financial stability. Furthermore, rates can be designed to send correct price signals at the same time as providing reasonable assurance to utilities that they will recover their revenue requirements. Decoupling the revenue requirement from sales, which has been adopted in California, provides the utilities with ample assurance that they will recover their prudently incurred costs. Fixed charges should be used to recover fixed costs not for the purpose of providing revenue stability but because such charges reflect cost causation.

II. Rate options

1. *What rate options should be offered to each type of customer, including bundled, direct access (DA), Community Choice Aggregation (CCA), and net-metering?*

As AMI is introduced to all customer classes, customers should see rates that reflect the impacts of their usage patterns on the utility system's costs. The goal should be to move to real-time pricing for some or all of the generation portion of bundled customer rates. This means that low system costs and well as high production costs should be signaled to bundled customers. Ideally, if the wholesale market were energy-based, these real-time prices would reflect hourly energy and ancillary service (A/S) costs and there would be no fixed demand charges for generation. This is currently not the case.

In such a theoretical energy-based market, there should be scarcity pricing, where the cost of energy and/or ancillary services increases dramatically as operating reserves are strained. These high prices should become a signal to customers that their incremental usage is imposing major strains on the system and that there is a risk of firm load curtailments. Customers can then decide whether they want to pay these high prices or reduce their electricity requirements to avoid them. Scarcity prices should not be driven by generation bids, which should be subject to offer caps. Rather, scarcity prices should reflect the potential cost of unserved load, aka the Value of Expected Unserved

Energy. This varies by customer class and this variation should also be taken into account. Customer classes that value service reliability more highly may wish to pay these high prices, whereas other customer classes may not. There are studies of the value of lost load and value of service by customer class that can be considered to determine if it would be appropriate to provide different levels of service reliability to different groups of customers.

As long as utilities pay for resource adequacy through separate capacity-type payments, a good case can be made that customers should see generation demand charges as well, reflecting the fact that not all generation costs are volumetric. This cost causation argument is inconsistent with Critical Peak Pricing ("CPP"), which rolls the cost of generation capacity into high-load-hour volumetric charges. However, the critical issue for CPP is whether rolling the fixed costs into the high-load-hour volumetric charges will result in demand response that will actually reduce the incurrence of such fixed costs. If not, one must ask the value of CPP pricing.

The issue of DA and CCA is somewhat different. The Commission does not know how the resources to supply these customers are provided or priced. For larger customers, many DA contracts are based on blocks of power, purchased in the forward market to match the customer's average load, and therefore are effectively hedge procurement prices. Usage above or below the block is purchased or sold in the short-term market. There is no reason why DA customers should not purchase hedges. The price they pay for the power they buy reflects the value of the hedge. For the Commission to attempt to tell non-utility load-serving entities ("LSEs") how they should price the power they sell to their customers would be to unravel such hedges. Proponents of RTP support the availability of hedging contracts, as long as the customer pays for the hedge. If the customer does not hedge, it will fully see the fluctuations of prices in the spot markets, which is certainly dynamic pricing. . Finally, the existence of hedges for DA customers does not influence the behavior of DA customers in such a way as to affect the cost or availability of utility generation resources for bundled customers.

2. *Which tariffs should be voluntary, default with opt-out provisions, or mandatory?*

Ultimately it would be best if customers saw default hourly real-time prices (at least on a day-ahead basis so they could respond) but had the ability to purchase hedges or have the utility hedge the cost of their power and pass the cost of the hedge on to them. The biggest problem with this proposal is that the forward market is not deep and may well over-charge for such hedges. Certainly customers in the East with default RTP pricing complain that hedging costs are often prohibitive.

Thus part of any transition to a default RTP must take into account the development of forward markets that are liquid and robust and can provide reasonable hedging opportunities. We see no reason to have mandatory RTP with no option to hedge, as long as customers pay for their hedges in a reasonable market.

In the meantime, the SDG&E default CPP market should be treated as an experiment. The statewide pricing project (SPP) provided useful information on a limited basis, but we are not yet convinced that the results will be duplicated in a system-wide default CPP approach. Despite the conclusions in the draft Brattle Report for the DRCC, the Commission should carefully study the SDG&E program before deciding that default CPP is the ultimate rate design.

3. *What are the advantages and disadvantages of rebates as an alternative to rates?*

Rebates are highly problematic. The purpose of dynamic pricing is to send price signals to customers that the cost of serving them at certain times is very high (and that it is not at other times). Rebates send no price signal. Unless the customer is already on a time-of-use rate, it pays its usual rate, which is *far less than* the cost of service during periods of tight supply and demand. The customer may reduce load to earn a rebate, or to be a good citizen, but there is no higher payment required of for the customer if it does nothing. This is not a price signal.

Furthermore, rebates require the use of a customer baseline (CBL) against which to determine a load reduction. There is extensive literature that demonstrates that it is very difficult to set a CBL that does not result in both significant free ridership and significant failure to provide rebates for customers who do respond with load reductions.

The limited experience with rebates in Anaheim and Ontario (the latter has not even been reported in any detail) does not provide sufficient justification for paying customers for load reductions. Furthermore, if other customers are seeing the incremental cost of usage at such high-load times through CPP or RTP, it is unfair to pay certain customers to reduce loads.

4. *Should automatic load control be considered as a substitute for dynamic pricing rates?*

Automatic load control is not a substitute for dynamic pricing but it is a very useful demand response tool. Air conditioner cycling and interruptible rates provide substantial amounts of load reduction during system emergencies, providing enormous value to the system. Furthermore, load control can be a complement to dynamic pricing. Enabling technologies like programmable "smart" thermostats or more elaborate forms of auto-DR that are triggered at times of high prices have been demonstrated to provide substantial load reductions when needed by the system, without the customer having to track prices and decide how to respond each time there are high electricity prices or CPP events.

The Statewide Pricing Pilot (SPP) demonstrated clearly the benefits of enabling technologies. The small commercial customers in the SPP showed no statistically significant response to high prices in CPP events unless they had enabling technology in the form of programmable thermostats.

> LT20 customers reduced peak-period energy use on critical weekdays by 14.3 percent. All of this reduction is attributable to the enabling technology. That is, this customer segment did not have any incremental price response. [2]

[2] Ibid. p. 13.

The response of residential customers in the SPP with these thermostats and central air conditioning was twice that of customers without them.[3]

> 5. *Should customers be offered a large variety of rate options so that customer can find a rate option that works for them, or should customers be offered a small number of options to avoid confusion, simplify marketing and minimize administrative costs?*

There are two problems with offering a large number of rate options. The first is adverse selection. Customers who pay attention to their rates will choose the rate option that results in the lowest bill consistent with the level of transactions costs they think they can tolerate. The second is that offering a large number of rate options almost guarantees that some of them will not be cost-based. While parties may debate how to calculate marginal costs and what cost-based means, it is clear that some rate designs will not reflect any reasonable definition of cost of service. The less cost-based the rate option, the greater the risk of cost shifting among customers. We recommend moving toward a cost-based RTP option and a hedged alternative, as discussed above.

> 6. *How should accuracy and simplicity be balanced in rate design?*

As discussed above, the two most important features of rates are that they be as cost-based as possible and that customers understand them. The latter does not inherently mean that they must be simple, just that they must be comprehensible and that a real effort must be made the give customers the tools they need to understand how they are being charged and how they can respond to the rates if they want to reduce their bills. The current residential tariffs are neither cost-based nor simple. There is plenty of room for improvement.

> 7. *How should the expected ability of a customer group to respond to time-differentiated rates be taken into consideration?*

Rates should be time differentiated because costs are. The question of whether or not a customer can respond is not an absolute "yes/no" question, nor should it act as a "veto" on the implementation of such rates. Technology can be very helpful in assisting

[3] Ibid.

customers to respond, whether it be in the form of auto-DR, permanent load shifting, programmable thermostats, or any one of a number of other options. Just as under AB 1X, residential usage up to 130% of baseline is priced well below the cost of providing it, setting rates for customers that are lower than the costs of serving them will simply cause them to use more power because they cannot make an economically rational decision on the basis of their rates. It would be far better to find cost-effective ways to assist them in responding to the actual costs of serving them.

8. *For customers that operate off-line and peaking generation facilities, how should the need to use system power for start-up operations be addressed?*

This question is not clear. However, if the issue is black start, the CAISO should have a black start A/S that sets a price for black start service. If the issue is standby service, standby rates charge customers with self generation facilities for demands placed on the system according to the nature and timing of the demands. This would include start-up operations for these customers.

9. *What is the expected response of demand to rate options, taking into account results of pilot programs and relevant studies?*

We don't think there is a definitive answer to this question. The SPP provides some indications. It shows that there is a residential response to CPP rates, but that the response varies considerably. It also shows that customers with enabling technology provide significantly higher levels of price response. On the other hand, small commercial customers showed no statistically significant price response without enabling technology. The SPP did not test larger customers. We discuss the results of the SPP more in later responses.

It is important to remember that the SPP did not involve random sampling SPP participants were actively solicited and received monetary incentives to participate. The results in the population at large may not be the same. Any estimate is complicated by the fact that the types of rates used in the SPP may not be able to be imposed until the AB 1X restrictions on residential and small commercial customer rates up to 130% of baseline are removed. The residential class, with its relatively low value of service and high saturation of air conditioning usage, is likely to be significantly price responsive. Air conditioning is the largest single contributor to system peak and to possible generation shortages. Yet, ironically, the residential class is the very class that is protected from providing price-responsive load reductions because its rates do not change as a function of time or market conditions and a significant portion of residential sales take place below cost.

We discuss the outcome of several other studies of customer response to dynamic pricing below:

The Energy Smart Pricing Plan in Illinois is the first real effort to introduce hourly market-based electricity pricing for residential customers. The program was developed by the Community Energy Cooperative in association with Commonwealth Edison and started in 2003. Customers were given day-ahead prices, with special notification if market prices were going to be particularly high. Prices were capped at 50 cents/kWh. The Cooperative provided energy education and individual usage information. The 2005 results show that residential customers did reduce electricity use in response to higher electricity prices. Their overall price elasticity was -4.7%, and was greatest during high priced late afternoon and evening hours. Furthermore, there was a conservation effect from the hourly pricing during the summer, with a reduction in usage of 3-4%. Automatic air conditioner cycling during high price periods increased the customers' price response.[4]

Ameren conducted a residential TOU/CPP pilot in 2004-2005. It found:

- The critical peak pricing component of the time-of-use rate does motivate customers to reduce demand during most of the CPP events, but does not appear effective in motivating customers to shift a statistically significant amount of load from the on-peak to off-peak or mid-peak periods.

- The enabling technology was a key component of the offering with the groups receiving the "smart" thermostat displaying much stronger load response (more than double) during CPP events when compared to the CPP only group. [5]

[4] "Evaluation of the 2005 Energy-Smart Pricing Plan: Final Report", Summit Blue Consulting, August 1, 2006.
[5] Voytas, Rick, "AmerenUE Critical Peak Pricing Pilot", December 15, 2006 Powerpoint presentation in DRCC webinar**.**

The Gulf Power Company in Florida has a program called GoodCents® *SELECT*. It combines residential service variable pricing (4 levels of price with high prices 11% of the time and CPP prices 1% of the time) with a residential advanced energy management system that gives customers control over their energy purchases by allowing them to program their central heating and cooling system, electric water heater and their pool pump to automatically respond to varying prices. Each home has a programmable gateway/interface that, in addition to allowing thermostat programming, enables the customer to program up to four devices in the home to respond to price signals.

Gulf Power has targeted its highest use residential customers. It has found that it can obtain a 2 kW demand reduction from a residential customer and that customers have accepted 100 CPP hours a year for event durations of 1-3 hours.[6] (We note that this is a shorter CPP event period than contemplated in California and are not surprised that customers are better able to respond for these shorter periods as discussed elsewhere in these comments.)

Regarding large electricity consumers, LBNL has performed extensive analysis of Niagara Mohawk's day-ahead real time pricing (RTP) for customers with demands over 2 MW. This analysis has shown an elasticity of substitution (as opposed to own price elasticity) of -0.11, or 11%. However, the response varied significantly by business sector. Manufacturers had the highest elasticity of substitution, at 16%. Government and education customers had an elasticity of 10%. The other sectors were less responsive, with commercial/retail at 6%, health care at 4% and public works at 2%. Eighteen percent of the customers provided 75-80% of the aggregate demand response.[7]

The Commission should also recall that it has already acknowledged that customers with loads over 500 kW in California have demonstrated a major flattening of load in response to existing time of use rates. The Commission discussed this finding in Decision 05-04-053 (mimeo, p. 18).

[6] "Good Cents Select: Advanced Energy Management Program". Powerpoint presentation.
[7] "Demand Response from Day-Ahead Hourly Pricing for Large Customers" LBNL-59630, April 2006.

10. Should customers be offered bill protection during an initial time period to learn how a rate might impact their bills?

There is merit in giving customers a year of bill protection, along with substantial education in new rate designs and how to respond to them, before they are fully subject to these new rates, particularly if the new rates are very different from those to which they are accustomed.

11. How would offering bill protection affect customers' response to dynamic pricing tariffs?

We are not sure there is enough evidence from past experiments to provide a definitive answer.

12. What are the potential distributional impacts of dynamic pricing rates?

We are not sure what the question means. If it refers to the bill impact of dynamic pricing, one must ask whether dynamic pricing is eliminating certain existing cross-subsidies among customers. Professor Severin Borenstein at the U.C. Energy Institute has written a paper on this subject in which he indicates that significant current cross-subsidization could be eliminated through alternative pricing mechanisms that have dynamic pricing aspects.[8]

III. Components of dynamic pricing tariffs

1. Which utility costs vary over time, vary with volume delivered, vary with demand, and/or are fixed? Which utility costs are fixed in the short run but vary in the long run?

All utility costs vary in the *very* long run, since a utility could theoretically lose all of its customers if it were cost-effective for customers to generate all of their own power, either individually or in groups. However, realistically:

- the costs of fuel and variable operation and maintenance vary volumetrically;

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[8] Borenstein, Severin, "Wealth Transfers Among Large Customers from Implementing Real-Time Retail Electricity Pricing", UCEI, July 2006, CSEM WP 156.

- the costs of generation capacity, including fixed O&M, vary with system coincident demand, which in turn varies with the time of day and season, and with plant availability but capacity does not vary volumetrically;
- the costs of transmission capacity vary with coincident demands *on the transmission system,* which is somewhat geographically dispersed (particularly the subtransmission system) and may have more localized peaks;
- the costs of distribution capacity vary with coincident demand *on the distribution system* but it is important to keep in mind that the distribution system is much more geographically dispersed than even the transmission/subtransmission system and may have localized peak demands; furthermore, distribution costs also arise as a function of creating accessibility to customers and hence these costs also vary as a function of the number of customers.

Price signals based on short-run marginal costs would consider all existing assets as fixed and of necessity add a shortage cost for certain time periods if demand exceeds the available capacity. Price signals based on long-run marginal costs would reflect the optimal addition of system resources to meet demand. Long run marginal costs are a better basis for developing rates as has been acknowledge by the Commission in a number of rate decisions.[9]

2. What costs should be recovered through the time-variant portion of the rate?

Costs that vary by time of day should be recovered through time-variant rates. There are two such types of costs. The volumetric ones should be recovered through time-varying volumetric rates. For example, fuel costs will vary by time of day because the heat rate of the incremental unit providing power or the market price of power that is purchased at the margin will so vary. Costs that vary with demand, but not volume, should, in general, be recovered through time-varying demand charges. The one possible exception is the recovery of generation capacity costs in CPP energy charges. This is not strictly cost-based, but may be seen as an experiment to send price signals more directly linked to the costs of very high load hours. Additionally, if the coincident demands on the distribution system vary a great deal so as to make it difficult to identify a single set of distribution time-of-use periods, it may be appropriate to make a choice between eliminating the time variant portion of distribution demand charges or adopting different rates for different regions of a utility's service territory. Finally, although transmission

[9] *See*, D.90-07-055, slip op. at 7-8; D.92-12-057, slip op. at 235-6; D.92-12-058, slip op. at 18-20.

costs are clearly time-variant, federal regulation dictates the manner in which these costs are recovered through rates.

3. How should time variant costs be determined?

This is the reason for cost of service studies. Many of these studies are not controversial. An issue that has provoked controversy is whether certain distribution capacity costs vary by time of day. . This involves evaluating to what extent, for each major distribution area, the coincident demands on the distribution (or subtransmission) system vary with time of day and whether these localized coincident demands occur in the same time of the year for most if not all of the distribution regions. PG&E has performed analyses and concluded that they do, although they peak at different times at different places on the system. SCE has concluded that there is less of such an effect on its system. SDG&E has not performed a detailed study of the time-variant nature of its distribution capacity costs. This is an area where more study is required.

Another issue that arises is to what extent distribution capacity costs are driven more by distribution demand or the number of customers served. PG&E and SCE have presented evidence in recent rate cases that some service extensions are sized more based on the number of new customer hookups than on distribution demand. Parties have disputed this evidence. This is another area where more study is required.

4. What is the appropriate time granularity for measuring electric service costs in connection with dynamic rate design—annual, monthly, weekly, daily, hourly, ten minutes, etc.?

For generation, it is clearly hourly, although for simplicity hourly costs for periods with similar cost causation patterns may be grouped into time-of-use periods. For distribution it is annual or seasonal unless studies indicate that peak coincident loads on the various portions of the distribution system occur at similar times throughout the utility's system or a decision is made to adopt different time-of-use period for different portions of the utility's system.

5. *How closely should the time profile of dynamic rates be aligned with the time profile of service costs?*

As closely as is feasible and comprehensible to the customer.

6. *If a time variant rate requires market price information, will the rate require information from the CAISO's Market Redesign and Technology Update (MRTU)?*

Yes, it will, assuming that the utility buys power from the CAISO day-ahead or real-time market as part of its regular procurement. As noted elsewhere, we believe that there is merit in setting prices equal to day-ahead CAISO hourly market prices.

Real-time pricing that is based on day-ahead or actual real-time prices will require information from the ISO's energy markets if the utilities are buying power from these markets at the margin. The cost should reflect the actual cost of the utility to supply that power to customer at the margin, whether it is self-supplied by the utility or purchased in the ISO's spot markets.

7. *Should some costs be recovered through a flat customer charge, demand charge, and/or non-varying per kW-hour charge?*

Costs such as those related to meters, service drops, final line transformers, and any other facilities that are essential to customer access, as well as customer service, billing, etc., should be recovered through flat customer charges. These costs do not vary with either customer demand or volumetric usage.

Costs that vary with demand on the system, whether generation, transmission, or distribution, should be recovered through demand charges. These may or may not vary with time of use.

There are no costs that vary in a manner that suggests that they be recovered through non-varying kWh charges.

8. *Should the components of the rate that are collecting fixed costs vary over time? If so, how should fixed costs be allocated to different time periods?*

As noted above, some demand-related costs vary by time of use. These include generation-related capacity costs. Certain studies suggest that certain distribution-related capacity costs also vary by time of day but also geography. To the extent that they vary with time of day or season, rates should vary to reflect these differences, so that customers that impose costs in lower cost hours pay for those lower costs, and vice versa.

9. *Should direct access and CCA customers be able to participate in time variant rates?*

For generation, this is an issue between the customers and their LSEs. For distribution, the direct access and CCA customers should face the same rate design as bundled customers, since it is provided in both cases by the utility.

10. *If a rate is intended to reduce load in the face of a short-term supply shortfall, should the design of the rate differ depending on whether the shortfall is forecast on a day-ahead or day-of basis?*

This may not be the best way to ask this question. If a customer is presented with a day-ahead real-time rate, the customer has the ability to respond to that rate by adjusting its usage pattern (operations, etc.) the next day. If a customer is presented with a real-time rate, it will not know until after the fact what the rate was and how it should have responded. Day-ahead RTP, while not perfect, gives the customer a chance to respond, which is highly desirable. Technological developments like auto-DR and the applications used in the Good Cents Program should enable customers in the future to respond on a real-time, same-day basis, making real-time RTP more feasible.

IV. Recovering the revenue requirement

1. *How can rates be designed to both recover the revenue requirement and communicate price information?*

You forget that we have rate decoupling in California. The utilities always recover their revenue requirement, the only question is when. This is not a justification for strictly volumetric rates, since the latter are not cost-justified. However, the utilities are assured rate recovery without having fixed charges.

2. *How can rates be designed to avoid large periodic rate adjustment to recover revenues?*

This is an age-old issue in rate design. Some jurisdictions change their fuel and purchased power rates every month so that there is no need for large adjustments to clear balancing accounts. This results in rate levels that change monthly, which is no doubt confusing to those customers who expect their rates to be stable for a while. In California, we used to consolidate as many rate changes as possible at the end of the year so that rates were stable for a year at a time. We no longer do this, simply because there are too many rate changes. The only way to avoid large period rate adjustments, as long as fuel and purchased power costs are somewhat volatile, is to adjust rates monthly. This still won't solve the problem as long as sales vary significantly from year to year with temperature. There is no good solution.

3. *Does the utility need to be able to forecast accurately the response of customers to these differential rates?*

If the Ruling is referring to dynamic pricing-based rates, the utility is not able to do this. There is not enough information on price elasticity. Fortunately the utility's revenue requirement is covered by decoupling. This is why the early years of any dynamic pricing program will be an experiment.

4. *Do the utilities need reliable estimates of price elasticities of demand for customers to make sales projections?*

These probably do not exist. There will have to be estimates, and tracking of revenues to see how over- or undercollections build up. If they become too big, the utilities can make trigger filings under ERRA.

5. *What estimates of price elasticities exist and can be relied upon for rate design purposes?*

We leave this one to the utilities.

6. *If customer responses to dynamic pricing tariffs result in revenue over- or under-collections, should the over-or under-collection be addressed by adjusting rates with the customer's class, or should the over- or under-collection be addressed by adjusting rates for all customer classes?*

In general, rates are designed to permit each class or schedule to recover the costs allocated to it. Thus, all else being equal, the cost recovery should be kept within the class or schedule. In turn, revenues are allocated across the various schedules that make up rates for the customer class. If there is large variation among schedules within a class, because some customers respond well and provide less revenues and some respond poorly, by schedule, the shortfall or overcollection might best stay within the schedule. Customers who respond well should get credit for the reduction in costs to serve them that resulted from their decreased usage at times of high cost. They will get such credit if they are allocated fewer costs for the following year because of their improved load shape. What is undesirable is to have customers switching schedules to take advantage of the load shapes of customers already on the schedule when their own load shapes are poorer. Thus both the allocation and the rates should be designed to reflect the beneficial usage patterns of the customers currently on the schedule that resulted in the reduction in costs. This issue requires some careful analysis.

7. *If customers' self-selection into voluntary dynamic pricing tariffs results in over-or under-collections how should the over- or under-collection be recovered—by adjusting rates of customers taking service under the voluntary tariff, by adjusting the rates of all customers within the customer's class, or by adjusting rates for all customers?*

For a voluntary option, the presumption should be to keep the shortfall within the class or schedule and then perform an allocation for the following year that reflects the revised usage pattern of the group of customers involved. Thus, if a schedule produces less revenue due to an improved load shape, it should be allocated less revenue during the allocation process for the following year.

8. *What mechanism should the utility use to recover over- and under-collections from customers?*

Recovery through ERRA, differentiated by class and schedule, is the most logical mechanism, since these costs are generation-related.

9. *Should dynamic pricing tariffs be revenue-neutral with respect to flat and less time-differentiated tariffs, or should the revenues collected by dynamic pricing tariffs differ from the revenues collected by flat and less time differentiated tariffs due to the incorporate of hedging premiums or participation credits?*

Dynamic pricing tariffs like CPP should probably start out revenue neutral for the first year. The results of the first year should provide some basis for determining whether customers on these dynamic pricing tariffs are actually less expensive to serve than customers on the otherwise applicable, less dynamic tariffs. CPP rates, unlike RTP rates, are based not on real market prices but on traditional rate design with one, albeit significant, adjustment. The concept of hedging applies more to the relationship between RTP and forward market prices.

It is premature to adjust for a hedging premium at this time. As discussed above, we can see a justification for an adjustment for a hedging premium compared to RTP, once 1) we have RTP from the MRTU market and 2) there is a viable, liquid, forward market that produces hedging premiums that do not appear to be manipulated.

We are not impressed by the concept of participation credits, or rebates, at this time.

10. *If the incorporation of hedging premiums or participation credits results in a revenue over-or under-collection, how should the revenue over- or under-collection be treated?*

We think it is premature to be considering this matter at this time.

11. *If the average cost to serve customers on a particular dynamic pricing tariff is less than the cost to serve customers not on the tariff, can the tariff be structure so that the dynamic pricing customers have a lower average cost?*

Of course. This would occur through the allocation process for the subsequent year, as discussed above. If the cost of service for customers on one schedule is lower, they should receive a lower relative cost allocation for the next year. This will result in a lower average rate for the schedule, compared to other schedules. However, what the individual customer pays will still be a function of its own usage pattern.

12. *If the utility incurs incremental costs to implement dynamic pricing tariffs (e.g. administrative costs, equipment, education), how should the incremental costs be recovered?*

In this case, these costs should be spread to all customers on an SAPC basis. These costs are more like RD&D costs than they are attributable to certain groups of customers on a cost of service basis.

V. Hedging

1. *Should customers have the opportunity to hedge the price risk under some or all of the dynamic tariff options?*

As discussed elsewhere, we think it is only fair for customers to hedge price risk under dynamic pricing options, if they pay the hedging costs. However, the costs of hedging should be based on the hedging costs of their supplier, whether it is the utility or another LSE. The current market prices for hedging reflect the thinness of the forward power market and may overstate the actual cost of the hedge.

2. *Should hedging options be offered by the utility, or should rates be structured so that hedging can be obtained externally in the marketplace?*

See answer above.

3. *If a hedging premium is incorporated into relatively flatter rates, what should the premium be and how should it be determined?*

This is not clear. We have heard from customers in the East that hedging premiums demanded by non-utility LSEs are excessive.

4. *Should customers have the opportunity to hedge through a two-part tariff in which part of their consumption is purchased at a fixed rate and the rest is purchased at the dynamic rate?*

Yes. The expectation of dynamic pricing is that customers will reduce, not eliminate, their consumption in response to high prices that signal high costs to serve their incremental demand. Even a 3-5% demand reduction would significantly free up generation operating reserves. During the summer of 2007, the CAISO indicated that a 1000 MW demand reduction during the hottest weather and most stressed system conditions (with a peak load of 48, 615 MW) was key to maintaining the operability of the power system.[10]

Furthermore, load reductions at times of system peak have the potential reduce the market clearing price in spot power markets. A report prepared for the PJM Interconnection (PJM) and the Mid-Atlantic Resources Initiative simulated the market impact of curtailing load by 3% in certain PJM zones during the top 20 five-hour blocks in 2005. The simulation indicated that the resulting 0.9% reduction in PJM's peak load would reduce energy market prices 5-8% on average.[11] While the results are based on a simulation, they suggest that exposing only a portion of customer load to RTP could be beneficial and might be worth consideration.

Professor Frank Wolak of Stanford University has stated:

> [The] combination of adequate fixed price forward contract coverage for essential load and real-time pricing for remaining load would virtually eliminate [the] ability of suppliers to exercise unilateral market power in [the] short-term market.[12]

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[10] CAISO Press Release Sept. 4, 2007.

[11] "Quantifying Demand Response Benefits in PJM", The Brattle Group, January 2007.

[12] Wolak, Frank, "Letting Electricity Consumers Benefit from Wholesale Competition"; presentation to Federal Trace Commission.

Allowing customers to hedge part of their loads should provide greater budgeting certainty for business and greater revenue stability for utilities, while still permitting significant price response.

VI. Sources of triggers and prices for dynamic rates?

1. *For trigger-based rates such as CPP, who should determine when an event is triggered—the CAISO or the utility?*

CLECA believes that the utility should trigger the event, since it is much closer to end use customers than the CAISO. The utility would be in constant contact with the CAISO, as at present, when it triggers air conditioner cycling and interruptible programs. With greater investment in smart grid technology, the utility will also know where distribution facilities like substations are facing overload conditions and will be in a position to trigger these programs on a locational basis if necessary.

2. *Should RTP be linked to wholesale market prices or some other price or cost information?*

The RTP should be based on the incremental cost to the utility of serving customer load. In any given hour, this will either be the utility's dispatch cost or the spot market price, depending on where the utility gets the incremental power. It should not be based on a forward market price, since that is not the marginal cost of providing the power.

We don't know yet how the utilities will operate under MRTU.

3. *If a RTP rate is linked to wholesale market prices, what wholesale market prices should the tariff be linked to?*

If the RTP rate is based on wholesale market prices, we recommend that the RTP be based on day-ahead ISO spot market prices. These prices should be communicated to customers by the prior afternoon so they can plan their usage patterns/operations in response to the prices.

4. *What impact will MRTU and potential capacity market implementation have on the prices used to design RTP and other dynamic tariffs?*

MRTU will provide day-ahead spot energy market prices. Unfortunately, capacity market implementation, if it happens, will result in substantial payments for generation capacity that are likely to suppress *energy* market prices and the price signals they provide. This will undermine the demand response aspects of RTP, compared to an energy-based market.

However, as discussed elsewhere in these comments, even with a capacity market, scarcity pricing during periods when operating reserves are strained has the ability to provide very significant price signals under RTP.

These energy market and scarcity price signals would be seriously blunted if the Commission were to adopt higher planning reserve margins to further reduce the level of expected unserved energy.

5. *Will the variation in wholesale market prices impact customer behavior?*

We are not sure what this question means. If customers see prices that vary, the expectation under dynamic pricing is that they will respond. We will find out once these rates are in place. If there is more price volatility that customers can handle, they should be able to hedge their price risk.

6. *Should tariffs be tied to the day-ahead or the same-day real time price?*

As noted above, customers will be better able to respond if the day-ahead price is used and communicated the afternoon before. This position is supported by a study performed by LBNL which states:

> "Default RTP rates that are indexed to the day-ahead energy market provide customers with a more compelling incentive for price response than those that are indexed to the real time market".[13]

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[13] "Killing Two Birds with One Stone: Can Real-Time Pricing Support Retail Competition and Demand Response?" LBNL-59739, August 2006, p. 13.

7. *How should the real time price be communicated to customers?*

It should be communicated 1) via a utility web site to larger customers and 2) via direct communication with a person designated by the customer to receive the information, via email or pager or phone.

8. *Should the RTP rate be a two-part rate with both a fixed price portion for part [of] a customer's usage and a dynamic portion for the remaining usage?*

Under RTP, the customer would have a two-part rate because only the generation portion of rates would be collected through RTP. The remainder of the utility's costs would be collected through customer, demand, and, as appropriate, volumetric rates. The generation rates could then be collected through a two-part rate as a means of providing – additional rate stability to customers while still providing strong price signals. Perhaps initially rates could be adopted that incorporate at least 50 percent of the generation revenue requirement into fixed generation charges. Over time, the amount of generation revenue requirement collected through fixed charges could potentially be adjusted downward as customer get used to the program.

9. *Under a two-part RTP rate, how should a customer's reference level for the fixed portion be determined?*

We think this question is premature. There is extensive literature on the subject of customer baselines that should be reviewed by a working group to determine the best methodology.

10. *Under a two-part RTP rate, what costs should be recovered in the fixed portion of the rate?*

Again, this should be discussed in a working group. Working group 3 in R. 02-06-001 spent considerable time on this issue. There are tradeoffs related to how to recover fixed costs for T&D versus generation costs. This is directly related to the customer baseline and whether the variable part of the tariff is only for generation. This subject is too complex to be dealt with through these comments.

VII. Residential rate issues

1. *What dynamic rates should be offered to residential customers while the rate protection offered under AB 1X remains in effect?*

2. *What types of dynamic rates can be offered to residential customers if the AB 1X rate protection is lifted by the Legislature or is no longer effective?*

As discussed earlier in these comments, there have been pilots and programs providing RTP and CPP rates to residential customers that have resulted in significant demand response. The Gulf Power Good Cents Select program successfully combined a four-part TOU rate with a CPP component and enabling technology. The Energy Smart Pricing Plan in Illinois showed good response to residential RTP. The SPP showed response to CPP rates that was greatly enhanced by enabling technology. CPP and RTP rates can be offered to residential customers once the AB 1X restrictions on the pricing of residential power are no longer in effect.

3. *How can rates be designed to maximize residential participation while the AB 1X rate protection remains in effect?*

4. *To what extent do existing residential rates and programs such as increasing block rates and air conditioning cycling fulfill the Commission's policy goals?*

5. *Could additional demand response be provided if AB 1X rate protection were no longer effective? If so, how much additional demand response? What would the potential bill impact be for residential customers if they were able to participate in dynamic pricing rates?*

The studies and programs cited earlier in this testimony, such as the Energy Smart Pricing Plan and Good Cents Select, as well as the SPP, show that CPP-type dynamic pricing, or RTP, particularly if combined with enabling technology, can produce very significant levels of demand response from residential customers.

6. *How would existing residential rates and program such as increasing block rates and air conditioning cycling be affected by dynamic pricing rates for residential customers?*

There is evidence that air conditioner cycling can complement residential RTP. This was found in the analysis of the Energy Smart Pricing Plan discussed earlier in these comments.

7. *Should low-income residential customers be offered discounted dynamic rates or other dynamic rate options?*

VIII. Critical Peak Pricing

1. *What should a CPP rate be based on? Is there a reliability value that is not included in wholesale power prices that should be incorporated into the tariff?*

What is meant by a reliability value? Does the question refer to ancillary services? Does it refer to scarcity pricing? If the latter, there may be merit in including a pass-through of scarcity prices during those rare periods when operating reserves are short. This means that there must be the development of a scarcity pricing proposal at the CAISO for the wholesale market that can be used for retail rate design purposes. We think this is an important issue and worthy of discussion at a workshop. The current CAISO scarcity pricing proposals do not consider the relevance to retail rate design.

2. *How long should the critical peak period be?*

Current utility summer on-peak TOU periods are very long for the imposition of high CPP rates. SDG&E's is 7 hours long and PG&E's and SCE's are 6 hours long. The price signals would be more effective is stimulating load reductions *without encouraging customers to opt out* if they were shorter. If a customer operates 9 am to 5 pm, or 10 am to 6 pm, under SDG&E's rates, the CPP event would be almost its entire working day. While this might be a high-cost period, it might work better if the CPP period for a customer were 3-4 hours and the customers were divided into two groups, each with a 3-4 hour CPP period. After all, the demand response desired from CPP is not a 20% load reduction, but closer to a 5% load reduction.

There are reports in the literature that support the increased effectiveness of a shorter CPP period. "Price response is highest for high prices of short duration, and falls rather dramatically as the duration of high prices increases."[14]

3. *When should a utility be able to trigger a critical peak period—during summer peak hours only, during summer mid-peak and off-peak hours, during winter hours?*

A CPP event should occur when the supply-demand balance is tight and reserves are tight. This could occur at any time that these criteria are met including hours outside of the summer on-peak period. The duration of the event and the amount and type of notice may be more important that the time of day or year. On the other hand, customers have learned to expect that there will be calls for demand reductions during hot summer days, and would have to be educated as to reasons why a CPP event might occur at a different time.

4. *How can a CPP tariff be structured to allow for a variable number of events each year while still recovering the revenue requirement?*

This issue was raised and addressed above.

5. *Is the potential customer savings or cost great enough under a CPP rate to motivate a customer response?*

This depends on the nature of the rate design, the duration of the event period, and the individual customer. As noted above, it is easier for some customers, such as commercial customers, to respond to shorter events, since they will respond by HVAC and lighting adjustments. Residential customers will also find it easier to respond to shorter events if they have substantial air conditioning load.

One should not assume that all customers will respond in a similar way to CPP or other dynamic prices. A recent LBNL study showed that, for large commercial and

[14] "Industrial and Commercial Customer Response to Real Time Electricity Prices", Neenan Associates; December 10, 2004, p. 3; available at www.bneenan.com.

industrial customers, "18% of the customers provide 75-80% of the aggregate demand response."[15]

We note here that the overall potential for demand response across all customer load is limited, since customers use electricity as an input to productive activities, not for its own sake, and reducing electricity demand results in a reduction in these productive activities. It is not clear what the maximum potential for demand response may be. Another recent study by LBNL states:

> Market assessments often examine the impact of differing rates of participation on program potential. Figure ES-1 illustrates the impact of aggressively marketing programs or promoting optional tariffs to achieve two and three times the base-case participation rates, which reflect current demand response experience. The results, on the order of 3-6 percent of non-residential peak demand, can be viewed as an approximate upper bound in demand response potentials.[16]

This report shows that default hourly pricing, aka RTP, has the largest potential to reduce class peak demand, at 3%, following by optional hourly pricing at 2%. CPP, on the other hand, only has the potential to reduce peak demand by about 1% for some customers and less than 1% across all customers over 350 kW. However, the report also notes that auto-DR, which involves technology-enabled DR, has a potential for significantly greater load reductions. This is consistent with the finding of the SPP, which shows that technology could roughly double residential response to CPP rates for customers with central air conditioning.

> All Track C customers had smart thermostats and central air conditioning…….
>
> The peak-period reduction for the Track C treatment equaled roughly 27 percent. About two-thirds of this reduction can be attributed to the enabling technology and the remainder is attributable to price-induced behavioral changes.[17]

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[15] "Demand Response from Day-Ahead Hourly Pricing for Large Customers", LBNL-59630, April 2006, p. 10.

[16] "Estimating Demand Response Market Potential among Large Commercial and Industrial Customers" A Scoping Study" LBNL 61498, January 2007, pp. xii-xiii..

[17] "Impact Evaluation of the California Statewide Pricing Pilot" Charles River Associates, March 16, 2005, Final Report, p. 9.

Similarly, for small (less than 20 kW) commercial and industrial ("C&I") customers, the SPP results showed:

> LT20 customers reduced peak-period energy use on critical weekdays by 14.3 percent. All of this reduction is attributable to the enabling technology. That is, this customer segment did not have any incremental price response.
>
> • GT20 customers reduced peak-period energy use on critical weekdays by 13.8 percent. Roughly 80 percent of this reduction is attributable to the enabling technology.[18]

IX. Relationship to reliability-oriented and other demand response programs.

1. *What is the purpose of reliability-oriented demand response tariffs and programs such as interruptible rates and programs and air conditioning cycling?*

The purpose of these tariffs and programs is to protect firm load from being shed at times when the operating reserves are below desired levels, either because of higher than forecast levels of demand on the power system or the unexpected loss of a generating plant or a transmission line. The load reductions from these programs are available on short notice. They have been used many times to avoid outages for firm service customers that might otherwise occur on the same day.[19]

2. *To what extent can dynamic pricing rates provide the reliability benefits that are provided by reliability-oriented tariffs and programs?*

There is no evidence that they can do so at this point. Reliability-oriented DR tariffs and programs are designed to be triggered by certain ISO-called events, like Stage 2 operating reserves. They result in significant well-documented load reductions that are "pre-paid" through tariffs. They can also be triggered on a locational basis. There is no track record of dynamic pricing providing reliable, defined load reductions over any period of time, on a system or on a locational basis. It will take a number of years to

[18] Ibid. p. 13.
[19] Indeed, emergency programs have been in existence and have operated for over 20 years.

determine how and to what degree customers respond to dynamic pricing and how reliably.

Respectfully Submitted,

/s/

William H. Booth
Law Offices of William H. Booth
1500 Newell Ave., 5th Floor
Walnut Creek, CA 94596
wbooth@booth-law.com
(925) 296-2460
925) 296-2464 facsimile
Counsel for the California Large Energy Consumers Association

October 5, 2007

CERTIFICATE OF SERVICE

I, the undersigned, declare that I am employed in the County of Contra Costa, California, that I am over the age of eighteen years and not a party to the within action. My business address is 1500 Newell Avenue, Fifth floor; Walnut Creek, CA 94596. On October 5, 2007, I electronically served a true copy of the document described as **OPENING COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION ON DYNAMIC PRICING ISSUES RAISED IN ASSIGNED COMMISSIONER'S RULING OF AUGUST 22, 2007** attached hereto on the accompanying service list

Executed on October 5, 2007 at Walnut Creek, California.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

/s/

Christine Dable

keith.mccrea@sablaw.com
jimross@r-c-s-inc.com
gtropsa@ice-energy.com
rkeen@manatt.com
klatt@energyattorney.com
douglass@energyattorney.com
francis.mcnulty@sce.com
maricruz.prado@sce.com
stacie.schaffer@sce.com
kfoley@sempra.com
lnelson@westernrenewables.com
pk@utilitycostmanagement.com
hayley@turn.org
marcel@turn.org
gxh@cpuc.ca.gov
pfa@cpuc.ca.gov
stephen.morrison@sfgov.org
norman.furuta@navy.mil
ek@a-klaw.com
sls@a-klaw.com
dfc2@pge.com
dss8@pge.com
rat9@pge.com
SAW0@pge.com
epoole@adplaw.com
jsqueri@gmssr.com
jwiedman@goodinmacbride.com
mday@goodinmacbride.com
tmacbride@goodinmacbride.com
ahk4@pge.com
dbyers@landuselaw.com
phanschen@mofo.com
wbooth@booth-law.com
cbaaqee@ebmud.com
rschmidt@bartlewells.com
bill@econsci.com
jpross@sungevity.com
tomb@crossborderenergy.com
joyw@mid.org
gayatri@jbsenergy.com
cmkehrein@ems-ca.com
francis.mcnulty@sce.com
glw@eslawfirm.com
lmh@eslawfirm.com
rob@clfp.com
rliebert@cfbf.com
atrowbridge@daycartermurphy.com

khojasteh.davoodi@navy.mil
ralph.dennis@constellation.com
smindel@knowledgeinenergy.com
sdbraithwait@caenergy.com
mbrubaker@consultbai.com
kjsimonsen@ems-ca.com
mark.s.martinez@sce.com
Case.Admin@sce.com
Jennifer.Shigekawa@sce.com
russell.worden@sce.com
CentralFiles@semprautilities.com
liddell@energyattorney.com
CManson@semprautilities.com
KCordova@semprautilities.com
casner@packetdesign.com
bruce.foster@sce.com
jeanne.sole@sfgov.org
tburke@sfwater.org
filings@a-klaw.com
nes@a-klaw.com
rosshemphill@fscgroup.com
stephengeorge@fscgroup.com
act6@pge.com
lrn3@pge.com
rrh3@pge.com
cem@newsdata.com
ahmad.faruqui@brattle.com
info@calseia.org
pthompson@summitblue.com
mrw@mrwassoc.com
wendy@econinsights.com
chrism@mid.org
brbarkovich@earthlink.net
bill@jbsenergy.com
rmccann@umich.edu
dgeis@dolphingroup.org
dcarroll@downeybrand.com
blaising@braunlegal.com
karen@klindh.com
rogerl47@aol.com
laura.rooke@pgn.com
agc@cpuc.ca.gov
bsk@cpuc.ca.gov
crv@cpuc.ca.gov
dkf@cpuc.ca.gov
bsl@cpuc.ca.gov
dlf@cpuc.ca.gov
fvr@cpuc.ca.gov
jef@cpuc.ca.gov
nil@cpuc.ca.gov

wtr@cpuc.ca.gov
bkb@cpuc.ca.gov
shn@cpuc.ca.gov
rwethera@energy.state.ca.us

CLECA058/pld/opening comm. On dyn pricing 10.05.07